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Unofficial electronic compilation of the
U.S. EPA Final Rule on Mandatory Reporting of Greenhouse Gases
incorporated by reference in California's Regulation for the
Mandatory Reporting of Greenhouse Gas Emissions

Unofficial Electronic Compilation

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ARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations (CCR), sections 95100-95157) incorporated by reference certain requirements promulgated by the United States Environmental Protection Agency (U.S. EPA) in its Final Rule on Mandatory Reporting of Greenhouse Gases (Title 40, Code of Federal Regulations (CFR), Part 98). Specifically, section 95100(c) of ARB's regulation incorporated those requirements promulgated by U.S. EPA as published in the Federal Register on October 30, 2009, July 12, 2010, September 22, 2010, October 28, 2010, November 30, 2010, December 17, 2010, and April 25, 2011.

This compilation combines the various incorporated Federal Register versions into one document for the reader's convenience; however, this compilation is not an official edition of either the CFR or the CCR. While reasonable steps have been taken to make this unofficial compilation accurate, the officially published requirements, found within the incorporated Federal Register notices with the dates listed above, take precedence if there are any discrepancies.

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40 CFR Part 98
Subpart W

Mandatory Reporting of Greenhouse Gases

Subpart W—Petroleum and Natural Gas Systems

Tables for Subpart W

§98.230 Definition of the source category.

(a) This source category consists of the following industry segments:

(1) Offshore petroleum and natural gas production. Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment

(FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) Onshore petroleum and natural gas production. Onshore petroleum and natural gas production means all equipment on a well pad or associated with a well pad (including compressors, generators, or storage facilities), and portable non-self-propelled equipment on a well pad or associated with a well pad (including well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations using CO_2, and all petroleum and natural gas production located on islands, artificial islands, or structures connected by a causeway to land, an island, or artificial island.

(3) Onshore natural gas processing. Natural gas processing separates and recovers natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas using equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing facility, whether inside or outside the processing facility fence. This source category does not include reporting of emissions from gathering lines and boosting stations. This source category includes:

(i) All processing facilities that fractionate.

(ii) All processing facilities that do not fractionate with throughput of 25 MMscf per day or greater.

(4) Onshore natural gas transmission compression. Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. In addition, transmission compressor station may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. This source category also does not include reporting of emissions from gathering lines and boosting stations – these sources are currently not covered by subpart W.

(5) Underground natural gas storage. Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(6) Liquefied natural gas (LNG) storage. LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to

capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

(7) LNG import and export equipment. LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(8) Natural gas distribution. Natural gas distribution means the distribution pipelines (not interstate transmission pipelines or intrastate transmission pipelines) and metering and regulating equipment at city gate stations, and excluding customer meters, that physically deliver natural gas to end users and is operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment excludes customer meters and infrastructure and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and "farm taps" upstream of the local distribution company inlet.

(b) [Reserved]

§98.231 Reporting threshold.

(a) You must report GHG emissions under this subpart if your facility contains petroleum and natural gas systems and the facility meets the requirements of §98.2(a)(2). Facilities must report emissions from the onshore petroleum and natural gas production industry segment only if emission sources specified in paragraph §98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year. Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in paragraph §98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(b) For applying the threshold defined in §98.2(a)(2), natural gas processing facilities must also include owned or operated residue gas compression equipment.

§98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraph (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.

(c) For an onshore petroleum and natural gas production facility, report CO_2, CH_4, and N_2O emissions from only the following source types on a well pad or associated with a well pad:

(1) Natural gas pneumatic device venting.

(2) [Reserved]

(3) Natural gas driven pneumatic pump venting.

(4) Well venting for liquids unloading.

(5) Gas well venting during well completions without hydraulic fracturing.

(6) Gas well venting during well completions with hydraulic fracturing.

(7) Gas well venting during well workovers without hydraulic fracturing.

(8) Gas well venting during well workovers with hydraulic fracturing.

(9) Flare stack emissions.

(10) Storage tanks vented emissions from produced hydrocarbons.

(11) Reciprocating compressor rod packing venting.

(12) Well testing venting and flaring.

(13) Associated gas venting and flaring from produced hydrocarbons.

(14) Dehydrator vents.

(15) [Reserved]

(16) EOR injection pump blowdown.

(17) Acid gas removal vents.

(18) EOR hydrocarbon liquids dissolved CO_2.

(19) Centrifugal compressor venting.

(20) [Reserved]

(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

(22) You must use the methods in §98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at an onshore production well pad. Stationary or portable equipment are the following equipment which are integral to the extraction, processing or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Dehydrator vents.

(5) Acid gas removal vents.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Transmission storage tanks.

(4) Blowdown vent stacks.

(5) Natural gas pneumatic device venting.

(6) [Reserved]

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(f) For underground natural gas storage, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Natural gas pneumatic device venting.

(4) [Reserved]

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(g) For LNG storage, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Equipment leaks from valves; pump seals; connectors; vapor recovery compressors, and other equipment leak sources.

(h) LNG import and export equipment, report CO_2 and CH_4 emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(i) For natural gas distribution, report emissions from the following sources:

(1) Above ground meters and regulators at custody transfer city gate stations, including equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Customer meters are excluded.

(2) Above ground meters and regulators at non-custody transfer city gate stations, including station equipment leaks. Customer meters are excluded.

(3) Below ground meters and regulators and vault equipment leaks. Customer meters are excluded.

(4) Pipeline main equipment leaks.

(5) Service line equipment leaks.

(6) Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in §98.233(z).

(j) All applicable industry segments must report the CO_2, CH_4, and N_2O emissions from each flare.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(l) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO_2 emissions captured and transferred off site by following the requirements of subpart PP.

§98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For actual conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) Natural gas pneumatic device venting. Calculate CH_4 and CO_2 emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W-1 of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24*365 \quad \text{(Eq. W-1)}$$

Where:

$Mass_{s,i}$	=	Annual total mass GHG emissions in metric tons CO_2e per year at standard conditions from a natural gas pneumatic device vent, for GHG i.
Count	=	Total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as determined in paragraph (a)(1) of this section.
EF	=	Population emission factors for natural gas pneumatic device venting listed in Tables W-1A, W-3, and W-4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.
GHG_i	=	For onshore petroleum and natural gas production facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas; for facilities listed in §98.230(a)(3) through (a)(8), GHG_i equals 1.
$Conv_i$	=	Conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2.
24 * 365	=	Conversion to yearly emissions estimate.

(1) For onshore petroleum and natural gas production, provide the total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as follows:

(i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(ii) In the second consecutive year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(iii) In the third consecutive calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.

(iv) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(2) For onshore natural gas transmission compression and underground natural gas storage, all natural gas pneumatic devices must be counted in the first year and updated every calendar year.

(b) [Reserved]

(c) Natural gas driven pneumatic pump venting. Calculate CH_4 and CO_2 emissions from natural gas driven pneumatic pump venting using Equation W-2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under paragraph (c) of this section.

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \qquad \text{(Eq. W-2)}$$

Where:

$Mass_{s,i}$	=	Annual total mass GHG emissions in metric tons CO_2e per year at standard conditions from all natural gas pneumatic pump venting, for GHG i.
Count	=	Total number of natural gas pneumatic pumps.
EF	=	Population emission factors for natural gas pneumatic pump venting listed in Tables W-1A of this subpart for onshore petroleum and natural gas production.
GHG_i	=	Concentration of GHG i, CH_4 or CO_2, in produced natural gas.
$Conv_i$	=	Conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2.
24 * 365	=	Conversion to yearly emissions estimate.

(d) Acid gas removal (AGR) vents. For AGR vent (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or through a flare, engine (e.g. permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (d) of this section.

(1) Calculation Methodology 1. If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If CEMS and/or volumetric flow rate monitor are not available, you may install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion).

(2) Calculation Methodology 2. If CEMS is not available, use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation W-3 of this section.

$$E_{a,}CO_2 = V_S * Vol CO_2 \qquad \text{(Eq. W-3)}$$

Where:

$E_{a,}CO_2$	=	Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in §98.234(b).

$VolCO_2$ = Volume fraction of CO_2 content in vent gas out of the AGR unit as determined in (d)(6) of this section.

(3) <u>Calculation Methodology 3.</u> If using CEMS or vent meter is not an option, use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equation W-4 of this section.

$$E_{a,CO2} = \left(V + \alpha * \left(V * \left(Vol_I - Vol_O\right)\right)\right) * \left(Vol_I - Vol_O\right) \quad \text{(Eq. W-4)}$$

Where:

$E_{a,}CO_2$ = Annual volumetric CO_2 emissions at actual condition, in cubic feet per year.

V = Total annual volume of natural gas flow into or out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.

α = Factor is 1 if the outlet stream flow is measured. Factor is 0 if the inlet stream flow is measured.

Vol_I = Volume fraction of CO_2 content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_O = Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) <u>Calculation Methodology 4.</u> Calculate emissions using any standard simulation software packages, such as AspenTech HYSYS® and API 4679 AMINECalc, that uses the Peng-Robinson equation of state, and speciates CO_2 emissions. A minimum of the following determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data must be used to characterize emissions:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate, and weight.

(5) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in §98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) If continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine $VolCO_2$ according to methods set forth in §98.234(b).

(7) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol_I according to methods set forth in §98.234(b).

(8) Determine volume fraction of CO_2 content in natural gas out of the AGR unit using one of the methods specified in paragraph (d)(8) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in §98.234(b).

(iii) Use sales line quality specification for CO_2 in natural gas.

(9) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (v) of this section.

(11) Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility.

(e) Dehydrator vents. For dehydrator vents, calculate annual CH_4, CO_2 and N_2O (when flared) emissions using calculation methodologies described in paragraphs (e)(1) or (e)(2) of this section.

(1) Calculation Methodology 1. Calculate annual mass emissions from dehydrator vents with throughput greater than or equal to 0.4 million standard cubic feet per day using a software program, such as AspenTech HYSYS® or GRI-GLYCalc, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (natural gas pneumatic/ air pneumatic/ electric).

(v) Absorbent circulation rate.

(vi) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

(vii) Use of stripping natural gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature and pressure.

(xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (e)(2)(xi) of this section.

(A) Use the wet natural gas composition as defined in paragraph (u)(2)(i) of this section.

(B) If wet natural gas composition cannot be determined using paragraph (u)(2)(i) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in §98.234(b)(1) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) Calculation Methodology 2. Calculate annual CH_4 and CO_2 emissions from glycol dehydrators with throughput less than 0.4 million cubic feet per day using Equation W-5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-5)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 74.5 for CH_4 and 3.26 for CO_2 at 68℉ and 14.7 psia or 73.4 for CH_4 and 3.21 for CO_2 at 60℉ and 14.7 psia.

Count = Total number of glycol dehydrators with throughput less than 0.4 million cubic feet.

1000 = Conversion of EF_i in thousand standard cubic to cubic feet.

(3) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1) or (e)(2) of this section downward by the magnitude of emissions captured.

(4) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(A) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) and (e)(2) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(5) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation W-6 of this section. Desiccant dehydrators covered in (e)(5) of this section do not have to report emissions under (i) of this section.

$$E_{s,n} = \frac{H*D^2*P*P_2*\%G*365days/yr}{4*P_1*T*1{,}000cf/Mcf*100} \qquad \text{(Eq. W-6)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.

H = Height of the dehydrator vessel (ft).

D = Inside diameter of the vessel (ft).

P_1 = Atmospheric pressure (psia).

P_2 = Pressure of the gas (psia).

P = pi (3.14).

%G = Percent of packed vessel volume that is gas.

T = Time between refilling (days).

100 = Conversion of %G to fraction.

(6) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(f) Well venting for liquids unloadings. Calculate CO_2 and CH_4 emissions from well venting for liquids unloading using one of the calculation methodologies described in paragraphs (f)(1), (f)(2) or (f)(3) of this section.

(1) Calculation Methodology 1. For one well of each unique well tubing diameter and producing horizon/formation combination in each gas producing field (see §98.238 for the definition of Field) where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (e.g. on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in §98.234(b). Calculate emissions from well venting for liquids unloading using Equation W-7 of this section.

$$E_{a,n} = \sum_h \sum_t T_{h,t} * FR_{h,t} \qquad \text{(Eq. W-7)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions in cubic feet.

$T_{h,t}$ = Cumulative amount of time in hours of venting from all wells of the same tubing diameter (t) and producing horizon (h)/formation combination during the year.

$FR_{h,t}$ = Average flow rate in cubic feet per hour of the measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

(i) Determine the well vent average flow rate as specified under paragraph (f)(1)(i) of this section.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter and producing horizon/formation combination in each producing field by averaging the recorded flow rates for the recorded time of one representative well venting to the atmosphere.

(B) This average flow rate is applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year for each reporting field and horizon starting the first calendar year of data collection.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) Calculation Methodology 2. Calculate emissions from each well venting for liquids unloading using Equation W-8 of this section.

$$E_{a,n} = \{(0.37\times10^{-3})*CD^2*WD*SP*N_V\}+\{SFR*(HR-1.0)*Z\} \quad \text{(Eq. W-8)}$$

Where:

$E_{a,n}$	=	Annual natural gas emissions at actual conditions, in cubic feet/year.
0.37×10^{-3}	=	{3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
CD	=	Casing diameter (inches).
WD	=	Well depth to first producing horizon (feet).
SP	=	Shut-in pressure (psia).
N_V	=	Number of vents per year.
SFR	=	Average sales flow rate of gas well in cubic feet per hour.
HR	=	Hours that the well was left open to the atmosphere during unloading.
1.0	=	Hours for average well to blowdown casing volume at shut-in pressure.
Z	=	If HR is less than 1.0 then Z is equal to 0. If HR is greater than or equal to 1.0 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) Calculation Methodology 3. Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W-9 of this section.

$$E_{a,n} = \{(0.37\times10^{-3})*TD^2*WD*SP*N_V\}+\{SFR*(HR-0.5)*Z\} \quad \text{(Eq. W-9)}$$

Where:

$E_{a,n}$	=	Annual natural gas emissions at actual conditions, in cubic feet/year.
0.37×10^{-3}	=	{3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).
TD	=	Tubing diameter (inches).
WD	=	Tubing depth to plunger bumper (feet).
SP	=	Sales line pressure (psia).
N_V	=	Number of vents per year.
SFR	=	Average sales flow rate of gas well in cubic feet per hour.
HR	=	Hours that the well was left open to the atmosphere during unloading.
0.5	=	Hours for average well to blowdown tubing volume at sales line pressure.
Z	=	If HR is less than 0.5 then Z is equal to 0. If HR is greater than or equal to 0.5 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) Gas well venting during completions and workovers from hydraulic fracturing. Calculate CH_4, CO_2 and N_2O (when flared) annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well workovers using Equation W-10 of this section. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

$$E_{a,n} = (T * FR) - EnF - SG \qquad \text{(Eq. W-10)}$$

Where:

$E_{a,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions following hydraulic fracturing.

T = Cumulative amount of time in hours of all well completion venting in a field during the year reporting.

FR = Average flow rate in cubic feet per hour, under actual conditions, converted to standard conditions, as required in paragraph (g)(1) of this section.

EnF = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job. If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO_2 then EnF is 0.

SG = Volume of natural gas in cubic feet at standard conditions that was recovered into a sales pipeline. If no gas was recovered for sales, SG is 0.

(1) The average flow rate for gas well venting to the atmosphere or to a flare during well completions and workovers from hydraulic fracturing shall be determined using either of the calculation methodologies described in this paragraph (g)(1) of this section.

(i) Calculation Methodology 1. For one well completion in each gas producing field and for one well workover in each gas producing field, a recording flow meter (digital or analog) shall be installed on the vent line, ahead of a flare if used, to measure the backflow venting event according to methods set forth in §98.234(b).

(A) The average flow rate in cubic feet per hour of venting to the atmosphere or routed to a flare is determined from the flow recording over the period of backflow venting.

(B) The respective flow rates are applied to all well completions in the producing field and to all well workovers in the producing field for the total number of hours of venting of each of these wells.

(C) New flow rates for completions and workovers are measured every other calendar year for each reporting gas producing field and gas producing geologic horizon in each gas producing field starting in the first calendar year of data collection.

(D) Calculate total volumetric flow rate at standard conditions using calculations in paragraph (t) of this section.

(ii) Calculation Methodology 2. For one well completion in each gas producing field and for one well workover in each gas producing field, record the well flowing pressure upstream(and downstream in subsonic flow) of a well choke according to methods set forth in §98.234(b) to calculate intermittent well flow rate of gas during venting to the atmosphere or a flare. Calculate emissions using Equation W-11 of this section for subsonic flow or Equation W-12 of this section for sonic flow:

$$FR = 1.27 * 10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1} \right)^{1.515} - \left(\frac{P_2}{P_1} \right)^{1.758} \right]} \qquad \text{(Eq. W-11)}$$

Where:

FR	=	Average flow rate in cubic feet per hour, under subsonic flow conditions.
A	=	Cross sectional area of orifice (m^2).
P_1	=	Upstream pressure (psia).
T_u	=	Upstream temperature (degrees Kelvin).
P_2	=	Downstream pressure (psia).
3430	=	Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$	=	Conversion from m^3/second to ft^3/hour.

$$FR = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \qquad \text{(Eq. W-12)}$$

Where:

FR	=	Average flow rate in cubic feet per hour, under sonic flow conditions.
A	=	Cross sectional area of orifice (m^2).
T_u	=	Upstream temperature (degrees Kelvin).
187.08	=	Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$	=	Conversion from m^3/second to ft^3/hour.

(A) The average flow rate in cubic feet per hour of venting across the choke is calculated for one well completion in each gas producing field and for one well workover in each gas producing field by averaging the gas flow rates during venting to the atmosphere or routing to a flare.

(B) The respective flow rates are applied to all well completions in the gas producing field and to all well workovers in the gas producing field for the total number of hours of venting of each of these wells.

(C) Flow rates for completions and workovers in each field shall be calculated once every two years for each reporting gas producing field and geologic horizon in each gas producing field starting in the first calendar year of data collection.

(D) Calculate total volumetric flow rate at standard conditions using calculations in paragraph (t) of this section.

(2) The volume of CO_2 or N_2 injected into the well reservoir during energized hydraulic fractures will be measured using an appropriate meter as described in 98.234(b) or using receipts of gas purchases that are used for the energized fracture job.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) The volume of recovered completion gas sent to a sales line will be measured using existing company records. If data does not exist on sales gas, then an appropriate meter as described in 98.234(b) may be used.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total emissions using calculations in paragraphs (u) and (v) of this section.

(5) Determine if the well completion or workover from hydraulic fracturing recovered gas with purpose designed equipment that separates saleable gas from the backflow, and sent this gas to a sales line (e.g. reduced emissions completion).

(i) Use the factor SG in Equation W-10 of this section, to adjust the emissions estimated in paragraphs (g)(1) through (g)(4) of this section by the magnitude of emissions captured using reduced emission completions as determined by engineering estimate based on best available data.

(ii) [Reserved]

(6) Calculate annual emissions from gas well venting during well completions and workovers from hydraulic fracturing to flares as follows:

(i) Use the total gas well venting volume during well completions and workovers as determined in paragraph (g) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers using hydraulic fracturing emissions from the flare. This adjustment to emissions from completions using flaring versus completions without flaring accounts for the conversion of CH_4 to CO_2 in the flare.

(h) Gas well venting during completions and workovers without hydraulic fracturing. Calculate CH_4, CO_2 and N_2O (when flared) emissions from each gas well venting during well completions and workovers not involving hydraulic fracturing and well workovers not involving hydraulic fracturing using Equation W-13 of this section:

$$E_{a,n} = N_{wo} * EF_{wo} + \sum_{f} V_f * T_f \qquad \text{(Eq. W-13)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions in cubic feet at actual conditions from gas well venting during well completions and workovers without hydraulic fracturing.

N_{wo} = Number of workovers per field not involving hydraulic fracturing in the reporting year.

EF_{wo} = Emission Factor for non-hydraulic fracture well workover venting in actual cubic feet per workover. EF_{wo} = 2,454 standard cubic feet per well workover without hydraulic fracturing.

f = Total number of well completions without hydraulic fracturing in a field.

V_f = Average daily gas production rate in cubic feet per hour of each well completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the wells produced to the sales line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_f = Time each well completion without hydraulic fracturing was venting in hours during the year.

(1) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(3) Calculate annual emissions from gas well venting during well completions and workovers not involving hydraulic fracturing to flares as follows:

(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (h) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers emissions without hydraulic fracturing from the flare.

(i) Blowdown vent stacks. Calculate CO_2 and CH_4 blowdown vent stack emissions from depressurizing equipment to the atmosphere (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

(1) Calculate the total volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimate based on best available data.

(2) If the total volume between isolation valves is greater than or equal to 50 standard cubic feet, retain logs of the number of blowdowns for each equipment type (including but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Blowdown volumes smaller than 50 standard cubic feet are exempt from reporting under paragraph (i) of this section.

(3) Calculate the total annual venting emissions for each equipment type using Equation W-14 of this section:

$$E_{s,n} = N * \left(V_v \left(\frac{(459.67 + T_s)P_a}{(459.67 + T_a)P_s} \right) - V_v * C \right) \quad \text{(Eq. W-14)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

N = Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.

V_v = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.

C = Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.

T_s = Temperature at standard conditions (^oF).

T_a = Temperature at actual conditions in the blowdown equipment chamber (^oF).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions in the blowdown equipment chamber (psia).

(4) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(5) Calculate total annual venting emissions for all blowdown vent stacks by adding all standard volumetric and mass emissions determined in Equation W-14 and paragraph (i)(4) of this section.

(j) Onshore production storage tanks. Calculate CH_4, CO_2 and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter), calculate annual CH_4 and CO_2 emissions using any of the calculation methodologies described in this paragraph (j).

(1) Calculation Methodology 1. For separators with oil throughput greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks using operating conditions in the last wellhead gas-liquid separator before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator enters an atmospheric pressure storage tank. A minimum of the following parameters determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data must be used to characterize emissions from liquid transferred to tanks.

(i) Separator temperature.

(ii) Separator pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by selecting one of the methods described under paragraph (j)(1)(viii) of this section.

(A) If separator oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator pressure first, and API gravity secondarily.

(B) If separator oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the field.

(C) Analyze a representative sample of separator oil in each field for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) Calculation Methodology 2. Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks for wellhead gas-liquid separators with oil throughput greater than or equal to 10 barrels per day by assuming that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in §98.234(b)(1) to sample and analyze separator oil composition at separator pressure and temperature.

(3) Calculation Methodology 3. For wells with oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks without passing through a wellhead separator, calculate CH_4 and CO_2 emissions by either of the methods in paragraph (j)(3) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of produced oil and gas from the field and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(ii) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match your well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(4) Calculation Methodology 4. For wells with oil production greater than or equal to 10 barrels per day that flow to a separator not at the well pad, calculate CH_4 and CO_2 emissions by either of the methods in paragraph (j)(4) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of oil at separator pressure determined by best available data and assume all of the CH_4 and CO_2 in the oil is emitted from the tank.

(ii) If well production oil composition is not available, use default oil composition in software programs, such as API 4697 E&P Tank, that most closely match your well production API gravity and pressure in the off-well pad separator determined by best available data. Assume all of the CH_4 and CO_2 in the oil phase is emitted from the tank.

(5) Calculation Methodology 5. For well pad gas-liquid separators and for wells flowing off a well pad without passing through a gas-liquid separator with throughput less than 10 barrels per day use Equation W-15 of this section:

$$E_{s,i} = EF_i * Count \qquad \text{(Eq. W-15)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Populations emission factor for separators and wells in thousand standard cubic feet per separator or well per year, for crude oil use 4.3 for CH_4 and 2.9 for CO_2 at 68°F and 14.7 psia, and for gas condensate use 17.8 for CH_4 and 2.9 for CO_2 at 68°F and 14.7 psia.

Count = Total number of separators and wells with throughput less than 10 barrels per day.

(6) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (j)(5) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(7) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine your contribution to storage tank emissions from the flare.

(8) Calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W-16 of this section.

$$E_{s,i} = (CF_n * E_n * T_n) + (E_t * (8760 - T_n)) \quad \text{(Eq. W-16)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.

E_n = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 5 in paragraphs (j)(1) through (j)(5) of this section (with wellhead separators) during time T_n in cubic feet per hour.

T_n = Total time the dump valve is not closing properly in the calendar year in hours. T_n is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

CF_n = Correction factor for tank emissions for time period T_n is 3.87 for crude oil production. Correction factor for tank emissions for time period T_n is 5.37 for gas condensate production. Correction factor for tank emissions for time period T_n is 1.0 for periods when the dump valve is closed.

E_t = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 3 in paragraphs (j)(1) through (j)(5) of this section at maintenance or operations during the time the dump valve is closing properly (ie.8760-T_n) in cubic feet per hour.

(9) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(k) Transmission storage tanks. For condensate storage tanks, either water or hydrocarbon, without vapor recovery or thermal control devices in onshore natural gas transmission compression facilities calculate CH_4, CO_2 and N_2O (when flared) annual emissions from compressor scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in §98.234(a)(1) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in §98.234(a)(5).

(2) If the tank vapors are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to quantify emissions:

(i) Use a meter, such as a turbine meter, to estimate tank vapor volumes according to methods set forth in §98.234(b). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in §98.234(a)(5).

(iii) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate emissions from storage tanks to flares as follows:

(i) Use the storage tank emissions volume and gas composition as determined in either paragraph (j)(1)of this section or with an acoustic leak detection device in paragraphs (k)(1) through (k)(3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions from the flare.

(l) Well testing venting and flaring. Calculate CH_4, CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the two procedures in paragraph (l)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in §98.234(b).

(3) Estimate venting emissions using Equation W-17 of this section.

$$E_{a,n} = GOR * FR * D \quad \text{(Eq. W-17)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Flow rate in barrels of oil per day for the well being tested.

D = Number of days during the year, the well is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from well testing to flares as follows:

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine well testing emissions from the flare.

(m) Associated gas venting and flaring. Calculate CH_4, CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing (refer to paragraph (l): Well testing venting and flaring of this section) as follows:

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same field shall be used.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (m)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in §98.234(b).

(3) Estimate venting emissions using Equation W-18 of this section.

$$E_{a,n} = GOR * V \qquad \text{(Eq. W-18)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from associated gas venting under actual conditions, in cubic feet.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

V = Volume of oil produced in barrels in the calendar year during which associated gas was vented or flared.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from associated natural gas to flares as follows:

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) Flare stack emissions. Calculate CO_2, CH_4, and N_2O emissions from a flare stack as follows:

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can install a flow measuring device on the flare or use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as follows:

(i) For onshore natural gas production, determine natural gas composition using (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.

(iii) When the stream going to the flare is a hydrocarbon product stream, such as ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations W-19, W-20, and W-21 of this section.

$$E_{a,CH4}(un-combusted) = V_a * (1-\eta) * X_{CH4} \quad \text{(Eq. W-19)}$$

$$E_{a,CO2}(un-combusted) = V_a * X_{CO2} \quad \text{(Eq. W-20)}$$

$$E_{a,CO2}(combusted) = \sum_j \eta * V_a * Y_j * R_j \quad \text{(Eq. W-21)}$$

Where:

$E_{a,}CH_4$(un-combusted) = Contribution of annual un-combusted CH_4 emissions from flare stack in cubic feet, under actual conditions.

$E_{a,}CO_2$(un-combusted) = Contribution of annual un-combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

$E_{a,}CO_2$(combusted) = Contribution of annual combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

V_a = Volume of gas sent to flare in cubic feet, during the year.

η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.

XCH_4 = Mole fraction of CH_4 in gas to the flare.

XCO_2 = Mole fraction of CO_2 in gas to the flare.

Y_j = Mole fraction of gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes-plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent *j*: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(7) Calculate total annual emission from flare stacks by summing Equation W-40, Equation W-19, Equation W-20 and Equation W-21 of this section.

(8) Calculate N_2O emissions from flare stacks using Equation W-40 in paragraph (z) of this section.

(9) The flare emissions determined under paragraph (n) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(o) Centrifugal compressor venting. Calculate CH_4, CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor covered by §98.232 (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2) you must conduct an annual measurement in the operating mode in which it is found. Measure emissions from all vents (including emissions manifolded to common vents) including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement.

(i) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors.

(ii) Operating mode, wet seal oil degassing vents.

(iii) Not operating, depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to 98.234(b) of this section. If you do not have a permanent flow meter, you may install a permanent flow meter on the wet seal oil degassing tank vent.

(3) For blowdown valve leakage and unit isolation valve leakage to open ended vents, you can use one of the following methods: calibrated bagging or high volume sampler according to methods set forth in §98.234(c) and §98.234(d), respectively. For through valve leakage, such as isolation valves, you may use an acoustic leak detection device according to methods set forth in §98.234(a). If you do not have a flow meter, you may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

(4) Estimate annual emissions using the flow measurement and Equation W-22 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} * (1 - B_m) \quad \text{(Eq. W-22)}$$

Where:

$E_{s,i,m}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

B_m = Fraction of operating time that the vent gas is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the time that vent gas is directed to the fuel gas system or sales.

(5) Calculate annual emissions from each centrifugal compressor using Equation W-23 of this section.

$$E_{s,i} = \sum_m EF_m * T_m * GHG_i \quad \text{(Eq. W-23)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each centrifugal compressor in cubic feet.

EF_m = Reporter emission factor for each mode m, in cubic feet per hour, from Equation W-24 of this section as calculated in paragraph 6.

T_m = Total time in hours per year the compressor was in each mode, as listed in paragraph (o)(1)(i) through (o)(1)(iii).

GHG_i = For onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in §98.230(a)(4) through (a)(8),GHG_i equals 1.

(6) You shall use the flow measurements of operating mode wet seal oil degassing vent, operating mode blowdown valve vent and not operating depressurized mode isolation valve vent for all the reporter's compressor modes not measured in the calendar year to

develop the following emission factors using Equation W-24 of this section for each emission source and mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

$$EF_m = \sum \frac{MT_m}{Count_m} \qquad \text{(Eq. W-24)}$$

Where:

EF_m = Reporter emission factors for compressor in the three modes m (as listed in paragraph (o)(1)(i) through (o)(1)(iii)) in cubic feet per hour.

MT_m = Flow Measurements from all centrifugal compressor vents in each mode in (o)(1)(i) through (o)(1)(iii) of this section in cubic feet per hour.

$Count_m$ = Total number of compressors measured.

m = Compressor mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

(i) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements in paragraph (o)(6) of this section.

(ii) [Reserved]

(7) Onshore petroleum and natural gas production shall calculate emissions from centrifugal compressor wet seal oil degassing vents as follows:

$$E_{s,i} = Count * EF_i \qquad \text{(Eq. W-25)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from centrifugal compressor wet seals in cubic feet.

Count = Total number of centrifugal compressors for the reporter.

EF_i = Emission factor for GHG i. Use 12.2 million standard cubic feet per year per compressor for CH_4 and 538 thousand standard cubic feet per year per compressor for CO_2 at 68℉ and 14.7 psia or 12 million standard cubic feet per year per compressor for CH_4 and 530 thousand standard cubic feet per year per compressor for CO_2 at 60℉ and 14.7 psia.

(8) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(9) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(i) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (o)(5) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine degassing vent vapor emissions from the flare.

(p) Reciprocating compressor venting. Calculate CH_4 and CO_2 emissions from all reciprocating compressor vents as follows. For each reciprocating compressor covered in §98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1) you must conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (p)(9) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement as follows:

(1) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(2) Operating mode, reciprocating rod packing emissions.

(3) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(i) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(ii) [Reserved]

(4) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line use one of the following two methods to calculate emissions:

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in §98.234 (c) and §98.234(d), respectively.

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in §98.234(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in §98.234(a).

(5) If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(i) You must use the methods described in §98.234 (a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(ii) Measure emissions found in paragraph (p)(5)(i) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to methods set forth in §98.234(b), (c), and (d), respectively.

(6) Estimate annual emissions using the flow measurement and Equation W-26 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} \qquad \text{(Eq. W-26)}$$

Where:

$E_{s,i,m}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG i in gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

(7) Calculate annual emissions from each reciprocating compressor using Equation W-27 of this section.

$$E_{s,i} = \sum_m EF_m * T_m * GHG_i \qquad \text{(Eq. W-27)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each reciprocating compressor in cubic feet.

EF_m = Reporter emission factor for each mode, m, in cubic feet per hour, from Equation W-28 of this section as calculated in paragraph (p)(7)(i) of this section.

T_m = Total time in hours per year the compressor was in each mode, m, as listed in paragraph (p)(1) through (p)(3).

GHG_i = For onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in §98.230(a)(4) through (a)(8), GHG_i equals 1.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(i) You shall use the flow meter readings from measurements of operating and standby pressurized blowdown vent, operating mode vents, not operating depressurized isolation valve vent for all the reporter’s compressor modes not measured in the calendar year to develop the following emission factors using Equation W-28 of this section for each mode as listed in paragraph (p)(1) through (p)(3).

$$EF_m = \sum \frac{MT_m}{Count_m} \qquad \text{(Eq. W-28)}$$

Where:

EF_m = Reporter emission factors for compressor in the three modes, m, in cubic feet per hour.

MT_m = Meter readings from all reciprocating compressor vents in each and mode, m, in cubic feet per hour.

$Count_m$ = Total number of compressors measured in each mode, m.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(A) You must combine emissions for blowndown vents, measured in the operating and standby pressurized modes.

(B) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements.

(ii) [Reserved]

(8) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (p)(7) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(9) Onshore petroleum and natural gas production shall calculate emissions from reciprocating compressors as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-29)}$$

Where:

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in cubic feet.
Count	=	Total number of reciprocating compressors for the reporter.
EF_i	=	Emission factor for GHG i. Use 9.63 thousand standard cubic feet per year per compressor for CH_4 and 0.535 thousand standard cubic feet per year per compressor for CO_2 at 68℉ and 14.7 psia or 9.48 thousand standard cu bic feet per year per compressor for CH_4 and 0.527 thousand standard cubic feet per year per compressor for CO_2. at 60℉ and 14.7 psia.

(10) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (u) and (v) of this section.

(q) Leak detection and leaker emission factors. You must use the methods described in §98.234(a) to conduct leak detection(s) of equipment leaks from all sources listed in **§**98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (q), calculate emissions using Equation W-30 of this section for each source with equipment leaks.

$$E_{s,i} = GHG_i * \sum_x EF_s * T_x \quad \text{(Eq. W-30)}$$

Where:

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.
x	=	Total number of this type of emissions source found to be leaking during T_x.
EF_s	=	Leaker emission factor for specific sources listed in Table W-2 through Table W-7 of this subpart.

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for other facilities listed in §98.230(a)(4) through (a)(8), GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.

T_x = The total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

(1) You must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (v) of this section.

(3) Onshore natural gas processing facilities shall use the appropriate default leaker emission factors listed in Table W-2 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table W-3 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table W-4 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(6) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table W-5 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(7) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table W-6 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(8) Natural gas distribution facilities for above ground meters and regulators at city gate stations at custody transfer, shall use the appropriate default leaker emission factors listed in Table W-7 of this subpart for equipment leak detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

(r) Population count and emission factors. This paragraph applies to emissions sources listed in §98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4) and (i)(5), on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation W-31 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \qquad \text{(Eq. W-31)}$$

Where:

$E_{s,i}$	=	Annual volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.
$Count_s$	=	Total number of this type of emission source at the facility. Average component counts are provided by major equipment piece in Tables W-1B and Table W-1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W-1D of this subpart.
EF_s	=	Population emission factor for the specific source, s listed in Table W-1A and Tables W-3 through Table W-7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W-1D of this subpart. EF for non-custody transfer city gate stations is determined in Equation W-32.
GHG_i	=	For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in §98.230(a)(4) through (a)(8),GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.
T_s	=	Total time the specific source s associated with the equipment leak emission was operational in the calendar year, in hours.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table W-1A of this subpart for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table 1-A of this subpart and major natural gas equipment in reference to Table W-1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table 1-A of this subpart and major crude oil equipment in reference to Table W-1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W-1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (r)(2). The same methodology must be used for the entire calendar year.

(i) Component Count Methodology 1. For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W-1B and Table W-1C of this subpart.

(B) Multiply major equipment counts by the average component counts listed in Table W-1B and W-1C of this subpart for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table W-1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W-1D of this subpart.

(ii) Component Count Methodology 2. Count each component individually for the facility. Use the appropriate factor in Table W-1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W-1D of this subpart.

(3) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table W-4 of this subpart for equipment leak from connectors, valves, pressure relief valves, and open ended lines.

(4) LNG storage facilities shall use the appropriate default population emission factors listed in Table W-5 of this subpart for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities shall use the appropriate default population emission factor listed in Table W-6 of this subpart for equipment leak from vapor recovery compressors.

(6) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (r)(6) of this section.

(i) Below grade meters and regulators; mains; and services, shall use the appropriate default population emission factors listed in Table W-7 of this subpart.

(ii) Above grade meters and regulators at city gate stations not at custody transfer as listed in §98.232(i)(2), shall use the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph (q)(8) of this section to develop facility emission factors using Equation W-32 of this section. The calculated facility emission factor from Equation W-32 of this section shall be used in Equation W-31 of this section.

$$EF = \sum \frac{E_{s,i}}{Count} \qquad \text{(Eq. W-32)}$$

Where:

EF = Facility emission factor for a meter at above grade M&R at city gate stations not at custody transfer in cubic feet per meter per year.

$E_{s,i}$ = Annual volumetric GHG emissions at standard condition from all equipment leak sources at all above grade M&R city gate stations at custody transfer, from paragraph (q) of this section.

Count = Total number of meter runs at all above grade M&R city gate stations at custody transfer.

(s) Offshore petroleum and natural gas production facilities. Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction shall report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, report the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS). Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction shall use monitoring methods and calculation methodologies published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, report the most recent reported emissions data with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to report emission from the facility sources.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle shall use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS) to report emissions.

(t) Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions by converting actual temperature and pressure of natural gas emissions to standard temperature and pressure of natural gas using Equation W-33 of this section.

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \qquad \text{(Eq. W-33)}$$

Where:

$E_{s,n}$	=	Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.
$E_{a,n}$	=	Natural gas volumetric emissions at actual conditions in cubic feet.
T_s	=	Temperature at standard conditions (^oF).
T_a	=	Temperature at actual emission conditions (^oF).
P_s	=	Absolute pressure at standard conditions (psia).
P_a	=	Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using Equation W-34 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \qquad \text{(Eq. W-34)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (^oF).

T_a = Temperature at actual emission conditions (^oF).

P_s = Absolute pressure at standard conditions (psia).

P_a = Absolute pressure at actual conditions (psia).

(u) GHG volumetric emissions. Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation W-35 of this section.

$$E_{s,i} = E_{s,n} * M_i \tag{Eq. W-35}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation W-35 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use your most recent gas composition based on available sample analysis of the field.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in §98.234(b).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(iv) GHG mole fraction in natural gas stored in underground natural gas storage facilities.

(v) GHG mole fraction in natural gas stored in LNG storage facilities.

(vi) GHG mole fraction in natural gas stored in LNG import and export facilities.

(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(v) GHG mass emissions. Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation W-36 of this section.

$$Mass_{s,i} = E_{s,i} * \rho_i * GWP * 10^{-3} \quad \text{(Eq. W-36)}$$

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass emissions at standard conditions in metric tons CO_2e.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG i. Use 0.0538 kg/ft^3 for CO_2 and N_2O, and 0.0196 kg/ft^3 for CH_4 at 68°F and 14.7 psia or 0.0530 kg/ft^3 for CO_2 and N_2O, and 0.0193 kg/ft^3 for CH_4 at 60°F and 14.7 psia .

GWP = Global warming potential, 1 for CO_2, 21 for CH_4, and 310 for N_2O.

(w) EOR injection pump blowdown. Calculate CO_2 pump blowdown emissions as follows:

(1) Calculate the total volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual venting emissions using Equation W-37 of this section:

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3} \quad \text{(Eq. W-37)}$$

Where:

$Mass_{c,i}$ = Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N = Number of blowdowns for the equipment in the calendar year.

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft^3. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.

GHG_i = Mass fraction of GHG_i in critical phase injection gas.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(x) EOR hydrocarbon liquids dissolved CO_2. Calculate dissolved CO_2 in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples must be taken according to methods set

forth in §98.234(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W-38 of this section.

$$Mass_{s,}CO_2 = S_{hl} * V_{hl} \quad \text{(Eq. W-38)}$$

Where:

$Mass_{s,}CO_2$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

(y) [Reserved]

(z) Onshore petroleum and natural gas production and natural gas distribution combustion emissions. Calculate CO_2 CH_4,and N_2O combustion-related emissions from stationary or portable equipment as follows:

(1) If the fuel combusted in the stationary or portable equipment is listed in Table C-1 of subpart C of this part, or is a blend of fuels listed in Table C-1, use the Tier 1 methodology described in subpart C of this part (General Stationary Fuel Combustion Sources). If the fuel combusted is natural gas and is pipeline quality and has a minimum high heat value of 950 Btu per standard cubic foot, then the natural gas emission factor and high heat values listed in Tables C-1 and C-2 of this part may be used.

(2) For fuel combustion units that combust field gas or process vent gas, or any blend of field gas or process vent gas and fuels listed in Table C-1 of subpart C of this part, calculate combustion emissions as follows:

(i) If you have a continuous flow meter on the combustion unit, you must use the measured flow volumes to calculate the total flow of gas to the unit. If you do not have a permanent flow meter on the combustion unit, you may install a permanent flow meter on the combustion unit, or use company records or engineering calculations based on best available data on heat duty or horsepower to estimate volumetric unit gas flow.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in paragraph (u)(2)(i) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W-39 of this section.

$$E_{a,CO2} = \sum_j V_a * Y_j * R_j \quad \text{(Eq. W-39)}$$

Where:

$E_{a,}CO_2$ = Contribution of annual emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to combustion unit in cubic feet, during the year.

Y_j = Concentration of gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent *j*; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions. You must report the type and number of each external fuel combustion unit.

(4) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(6) Calculate N_2O mass emissions using Equation W-40 of this section.

$$Mass_{N_2O} = \left(1\times10^{-3}\right)\times Fuel \times HHV \times EF \times GWP \quad \text{(Eq. W-40)}$$

Where:

N_2O = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = High heat value of the fuel from paragraphs (z)(8)(i),(z)(8)(ii) or (z)(8)(iii) of this section (units must be consistent with Fuel).

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(i) For fuels listed in Table C-1 of subpart C of this part, use the provided default HHV in the table.

(ii) For field gas or process vent gas, use 1.235×10^{-3} mmBtu/scf for HHV.

(iii) For fuels not listed in Table C-1 of subpart C of this part and not field gas or process vent gas, you must use the methodology set forth in the Tier 2 methodology described in subpart C of this part to determine HHV.

§98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in §98.233(k), (o), (p) and (q) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) Optical gas imaging instrument. Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2) of the *Alternative work practice for monitoring equipment leaks.* Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A-7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(2) Method 21. Use the equipment leak detection methods in 40 CFR part 60, appendix A-7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph(a)(1) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) Infrared laser beam illuminated instrument. Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) Optical gas imaging instrument. An optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(5) Acoustic leak detection device. Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters.

(b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in §98.233 according to the procedures in §98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in §98.233(t).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(e) Peng Robinson Equation of State means the equation of state defined by Equation W-41 of this section:

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \quad \text{(Eq. W-41)}$$

Where:

p = Absolute pressure.

R = Universal gas constant.

T = Absolute temperature.

V_m = Molar volume.

$$a = \frac{0.45724 R^2 T_c^2}{p_c}$$

$$b = \frac{0.7780 R T_c}{p_c}$$

$$\alpha = \left(1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2\right)\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2 \quad \text{(Eq. W-42)}$$

Where:

ω = Acentric factor of the species.

T_c = Critical temperature.

P_c = Critical pressure.

(f) Special reporting provisions

(1) Best available monitoring methods. EPA will allow owners or operators to use best available monitoring methods for parameters in §98.233 Calculating GHG Emissions as specified in paragraphs (f)(2), (f)(3), and (f)(4) of this section. If the reporter anticipates the potential need for best available monitoring for sources for which they need to petition EPA and the situation is unresolved at the time of the deadline, reporters should submit written notice of this potential situation to EPA by the specified deadline for requests to be considered. EPA reserves the right to review petitions after the deadline but will only consider and approve late petitions which demonstrate extreme or unusual circumstances. The Administrator reserves to right to request further information in regard to all petition requests. The owner or operator must use the calculation methodologies and equations in §98.233 Calculating GHG Emissions. Best available monitoring methods means any of the following methods specified in paragraph (f)(1) of this section:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) Best available monitoring methods for well-related emissions. During January 1, 2011 through September 30, 2011, owners or operators may use best available monitoring methods for any well-related data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart, and only where required measurements cannot be duplicated due to technical limitations after September 30, 2011. These well-related sources are:

(i) Gas well venting during well completions and workovers with hydraulic fracturing as specified in §98.233(g).

(ii) Well testing venting and flaring as specified in §98.233(l).

(3) Best available monitoring methods for specified activity data. During January 1, 2011 through September 30, 2011, owners or operators may use best available monitoring methods for activity data as listed below that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart, specifically for events that generate data that can be collected only between January 1, 2011 and September 30, 2011 and cannot be duplicated after September 30, 2011. These sources are:

(i) Cumulative hours of venting, days, or times of operation in §98.233(e), (f), (g), (h), (l), (o), (p), (q), and (r).

(ii) Number of blowdowns, completions, workovers, or other events in §98.233(f), (g), (h), (i), and (w).

(iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs §98.233(d), (e), (j), (k), (l), (m), (n), (x), (y), and (z).

(4) Best available monitoring methods for leak detection and measurement. The owner or operator may request use of best available monitoring methods between January 1,

2011 and December 31, 2011 for sources requiring leak detection and/or measurement. These sources include:

(i) Reciprocating compressor rod packing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in §98.232 (d)(1), (e)(1), (f)(1), (g)(1), and (h)(1).

(ii) Centrifugal compressor wet seal oil degassing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in §98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2).

(iii) Acid gas removal vent stacks in onshore petroleum and natural gas production and onshore natural gas processing as specified in §98.232(c)(17) and (d)(6).

(iv) Equipment leak emissions from valves, connectors, open ended lines, pressure relief valves, block valves, control valves, compressor blowdown valves, orifice meters, other meters, regulators, vapor recovery compressors, centrifugal compressor dry seals, and/or other equipment leaks in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and natural gas distribution as specified in §98.232 (d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1).

(v) Condensate (oil and/or water) storage tanks in onshore natural gas transmission compression as specified in §98.232(e)(3).

(5) Requests for the use of best available monitoring methods. The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods.

(i) No request or approval by the Administrator is necessary to use best available monitoring methods between January 1, 2011 and September 30, 2011 for the sources specified in paragraph (f)(2) of this section.

(ii) No request or approval by the Administrator is necessary to use best available monitoring methods between January 1, 2011 and September 30, 2011 for the sources specified in paragraph (f)(3) of this section.

(iii) Owners or operators must submit a request and receive approval by the Administrator to use best available monitoring methods between January 1, 2011 and December 31, 2011 for sources specified in paragraph (f)(4) of this section.

(A) Timing of request. The request to use best available monitoring methods for paragraph (f)(4) of this section must be submitted to EPA no later than July 31, 2011.

(B) Content of request. Requests must contain the following information for sources listed in paragraph (f)(4) of this section:

(1) A list of specific source types and specific equipment, monitoring instrumentation, and/or services for which the request is being made and the locations where each piece of monitoring instrumentation will be installed or monitoring service will be supplied.

(2) Identification of the specific rule requirements (by subpart, section, and paragraph number) for which the instrumentation or monitoring service is needed.

(3) Documentation which demonstrates that the owner or operator made all reasonable efforts to obtain the information, services or equipment necessary to comply with subpart

W reporting requirements, including evidence of specific service or equipment providers contacted and why services or information could not be obtained during 2011.

(4) A description of the specific actions the facility will take to obtain and/or install the equipment or obtain the monitoring service as soon as reasonably feasible and the expected date by which the equipment will be obtained and operating or service will be provided.

(C) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it does not own the required monitoring equipment, and it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment or to obtain leak detection or measurement services in order to meet the requirements of this subpart for 2011.

(iv) EPA does not anticipate a need to approve the use of best available monitoring methods for sources not listed in paragraphs(f)(2), (f)(3), and (f)(4) of this section; however, EPA will review such requests if submitted in accordance with paragraph (f)(5)(iv)(A)-(C) of this section.

(A) Timing of request. The request to use best available monitoring methods for sources not listed in paragraphs (f)(2), (f)(3), and (f)(4) of this section must be submitted to EPA no later than July 31, 2011.

(B) Content of request. Requests must contain the following information:

(1) A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.

(2) A description of the data collection methodologies that do not meet safety regulations, technical infeasibility, or specific laws or regulations that conflict with each specific source for which an owner or operator is requesting use of best available monitoring methodologies.

(3) A detailed explanation and supporting documentation of how and when the owner or operator will receive the services or equipment to comply with all subpart W reporting requirements.

(C) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that the owner or operator faces unique safety, technical or legal issues rendering them unable to meet the requirements of this subpart for 2011.

(6) Requests for extension of the use of best available monitoring methods through December 31, 2011 for sources in paragraph (f)(2) of this section. The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods described in paragraph (f)(2) of this section beyond September 30, 2011.

(i) Timing of request. The extension request must be submitted to EPA no later than July 31, 2011.

(ii) Content of request. Requests must contain the following information:

(A) A list of specific source types and specific equipment, monitoring instrumentation, contract modifications, and/or services for which the request is being made and the locations where each piece of monitoring instrumentation will be installed, monitoring service will be supplied, or contracts will be modified.

(B) Identification of the specific rule requirements (by subpart, section, and paragraph number) for which the instrumentation, contract modification, or monitoring service is needed.

(C) A description and applicable correspondence outlining the diligent efforts of the owner or operator in obtaining the needed equipment or service and why they could not be obtained and installed in a period of time enabling completion of applicable requirements of this subpart within the 2011 calendar year.

(D) If the reason for the extension is that the owner or operator cannot collect data from a service provider or relevant organization in order for the owner or operator to meet requirements of this subpart for the 2011 calendar year, the owner or operator must demonstrate a good faith effort that it is not possible to obtain the necessary information, service or hardware which may include providing correspondence from specific service providers or other relevant entities to the owner or operator, whereby the service provider states that it is unable to provide the necessary data or services requested by the owner or operator that would enable the owner or operator to comply with subpart W reporting requirements by September 30, 2011.

(E) A description of the specific actions the owner or operator will take to comply with monitoring requirements in 2012 and beyond.

(iii) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to obtain the data necessary to meet the requirements of this subpart for the sources specified in paragraph (f)(2) of this section by September 30, 2011.

(7) Requests for extension of the use of best available monitoring methods through December 31, 2011 for sources in paragraph (f)(3) of this section. The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods described in paragraph (f)(3) of this section beyond September 30, 2011.

(i) Timing of request. The extension request must be submitted to EPA no later than July 31, 2011.

(ii) Content of request. Requests must contain the following information:

(A) A list of specific source types for which data collection could not be implemented.

(B) Identification of the specific rule requirements (by subpart, section, and paragraph number) for which the data collection could not be implemented.

(C) A description of the data collection methodologies that do not meet safety regulations, technical infeasibility, or specific laws or regulations that conflict with each specific source for which an owner or operator is requesting use of best available monitoring methodologies for which data collection could not be implemented in the 2011 calendar year.

(iii) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to implement the data collection for the sources described in paragraph (f)(3) of this section for the methods required in this subpart by September, 30, 2011.

(8) Requests for extension of the use of best available monitoring methods beyond 2011 for sources listed in paragraphs (f)(2), (f)(3), (f)(4), (f)(5)(iv) of this section and other sources in this subpart. EPA does not anticipate a need for approving the use of best available methods beyond December 31, 2011, except in extreme circumstances, which include safety, a requirement being technically infeasible or counter to other local, State, or Federal regulations.

(i) Timing of request. The request to use best available monitoring methods for paragraphs (f)(2), (f)(3), (f)(4), (f)(5)(iv) of this section and sources not listed in paragraphs (f)(2), (f)(3), (f)(4), (f)(5)(iv) of this section must be submitted to EPA no later than September 30, 2011.

(ii) Content of request. Requests must contain the following information:

(iii) A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.

(iv) A description of the data collection methodologies that do not meet safety regulations, technical infeasibility, or specific laws or regulations that conflict with each specific source for which an owner or operator is requesting use of best available monitoring methodologies.

(v) A detailed explanation and supporting documentation of how and when the owner or operator will receive the services or equipment to comply with all of this subpart W reporting requirements.

(C) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that the owner or operator faces unique safety, technical or legal issues rendering them unable to meet the requirements of this subpart.

§98.235 Procedures for estimating missing data.

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, you must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the year in which data are collected, until valid data for reporting is obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection. For missing data which are continuously monitored or measured, (for example flow meters), or for missing temperature or pressure data that are required under §98.236, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

§98.236 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain reported emissions and related information as specified in this section.

(a) Report annual emissions separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section in metric tons CO_2e per year at standard conditions. For each segment, report emissions from each source type §98.232(a) in the aggregate, unless specified otherwise. For example, an onshore natural gas production operation with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.

(1) Onshore petroleum and natural gas production.

(2) Offshore petroleum and natural gas production.

(3) Onshore natural gas processing.

(4) Onshore natural gas transmission compression.

(5) Underground natural gas storage.

(6) LNG storage.

(7) LNG import and export.

(8) Natural gas distribution. Report each source in the aggregate for pipelines and for Metering and Regulating (M&R) stations.

(b) Offshore petroleum and natural gas production is not required to report activity data and emissions for each aggregated source under §98.236 (c). Reporting requirements for offshore petroleum and natural gas production is set forth by BOEMRE in compliance with 30 CFR 250.302 through 304.

(c) For each aggregated source, unless otherwise specified, report activity data and emissions (in metric tons CO_2e per year at standard conditions) for each aggregated source type as follows:

(1) For natural gas pneumatic devices (refer to Equation W-1 of §98.233), report the following:

(i) Actual count and estimated count separately of natural gas pneumatic high bleed devices as applicable.

(ii) Actual count and estimated count separately of natural gas pneumatic low bleed devices as applicable.

(iii) Actual count and estimated count separately of natural gas pneumatic intermittent bleed devices as applicable.

(iv) Report emissions collectively.

(2) For natural gas driven pneumatic pumps (refer to Equation W-2 of §98.233), report the following,

(i) Count of natural gas driven pneumatic pumps.

(ii) Report emissions collectively.

(3) For each acid gas removal unit (refer to Equation W-3 and Equation W-4 of §98.233), report the following:

(i) Total throughput off the acid gas removal unit using a meter or engineering estimate based on process knowledge or best available data in million cubic feet per year.

(ii) For Calculation Methodology 1 and Calculation Methodology 2 of §98.233(d), fraction of CO_2 content in the vent from the acid gas removal unit (refer to §98.233(d)(6)).

(iii) For Calculation Methodology 3 of §98.233(d), volume fraction of CO_2 content of natural gas into and out of the acid gas removal unit (refer to §98.233(d)(7) and (d)(8)).

(iv) Report emissions from the AGR unit recovered and transferred outside the facility.

(v) Report emissions individually.

(4) For dehydrators, report the following:

(i) For each Glycol dehydrator with a throughput greater than or equal to 0.4 MMscfd (refer to §98.233(e)(1)), report the following:

(A) Glycol dehydrator feed natural gas flow rate in MMscfd, determined by engineering estimate based on best available data.

(B) Glycol dehydrator absorbent circulation pump type.

(C) Whether stripper gas is used in glycol dehydrator.

(D) Whether a flash tank separator is used in glycol dehydrator.

(E) Type of absorbent.

(F) Total time the glycol dehydrator is operating in hours.

(G) Temperature, in degrees Fahrenheit and pressure, in psig, of the wet natural gas.

(H) Concentration of CH_4 and CO_2 in natural gas.

(I) What vent gas controls are used (refer to §98.233(e)(3) and (e)(4)).

(J) Report vent and flared emissions individually.

(ii) For all glycol dehydrators with a throughput less than 0.4 MMscfd (refer to §98.233, Equation W-5 of §98.233), report the following:

(A) Count of glycol dehydrators.

(B) Whether any vent gas controls are used (refer to §98.233(e)(3) and (e)(4)).

(C) Report vent emissions collectively.

(iii) For absorbent desiccant dehydrators (refer to Equation W-6 of §98.233), report the following:

(A) Count of desiccant dehydrators.

(B) Report emissions collectively.

(5) For well venting for liquids unloading (refer to Equations W-7, W-8 and W-9 of §98.233), report the following by field:

(i) Count of wells vented to the atmosphere for liquids unloading.

(ii) Count of plunger lifts.

(iii) Cumulative number of unloadings vented to the atmosphere.

(iv) Average flow rate of the measured well venting in cubic feet per hour (refer to §98.233(f)(1)(i)(A)).

(v) Average casing diameter in inches.

(vi) Report emissions collectively.

(6) For well completions and workovers, report the following for each field:

(i) For gas well completions and workovers with hydraulic fracturing (refer to Equation W-10 of §98.233):

(A) Total count of completions in calendar year.

(B) Average flow rate of the measured well completion venting in cubic feet per hour (refer to §98.233(g)(1)(i) or (g)(1)(ii)).

(C) Total count of workovers in calendar year.

(D) Average flow rate of the measured well workover venting in cubic feet per hour (refer to §98.233(g)(1)(i) or (g)(1)(ii)).

(E) Total number of days of gas venting to the atmosphere during backflow for completion.

(F) Total number of days of gas venting to the atmosphere during backflow for workovers.

(G) Report number of completions and workovers employing reduced emissions completions and engineering estimate based on best available data of the amount of gas recovered to sales.

(H) Report vent emissions collectively. Report flared emissions collectively.

(ii) For gas well completions and workovers without hydraulic fracturing (refer to Equation W-13 of §98.233):

(A) Total count of completions in calendar year.

(B) Total count of workovers in calendar year.

(C) Total number of days of gas venting to the atmosphere during backflow for completion.

(D) Report vent emissions collectively. Report flared emissions collectively.

(7) For each blowdown vent stack (refer to Equation W-14 of §98.233), report the following:

(i) Total number of blowdowns per equipment type in calendar year.

(ii) Report emissions collectively per equipment type.

(8) For gas emitted from produced oil sent to atmospheric tanks:

(i) For wellhead gas-liquid separator with oil throughput greater than or equal to 10 barrels per day, using Calculation Methodology 1 and 2 of §98.233(j), report the following by field:

(A) Number of wellhead separators sending oil to atmospheric tanks.

(B) Estimated average separator temperature, in degrees Fahrenheit, and estimated average pressure, in psig.

(C) Estimated average sales oil stabilized API gravity, in degrees.

(D) Count of hydrocarbon tanks at well pads.

(E) Best estimate of count of stock tanks not at well pads receiving your oil.

(F) Total volume of oil from all wellhead separators sent to tank(s) in barrels per year.

(G) Count of tanks with emissions control measures, either vapor recovery system or flaring, for tanks at well pads.

(H) Best estimate of count of stock tanks assumed to have emissions control measures not at well pads, receiving your oil.

(I) Range of concentrations of flash gas, CH_4 and CO_2.

(J) Report emissions individually for Calculation Methodology 1 and 2 of §98.233(j).

(ii) For wells with oil production greater than or equal to 10 barrels per day, using Calculation Methodology 3 and 4 of §98.233(j), report the following by field:

(A) Total volume of sales oil from all wells in barrels per year.

(B) Total number of wells sending oil directly to tanks.

(C) Total number of wells sending oil to separators off the well pads.

(D) Sales oil API gravity range for (B) and (C) of this section, in degrees.

(E) Count of hydrocarbon tanks on wellpads

(F) Count of hydrocarbon tanks, both on and off well pads assumed to have emissions control measures: either vapor recovery system or flaring of tank vapors.

(G) Report emissions collectively for Calculation Methodology 3 and 4 of §98.233(j).

(iii) For wellhead gas-liquid separators and wells with throughput less than 10 barrels per day, using Calculation Methodology 5 of §98.233(j) Equation W-15 of §98.233), report the following:

(A) Number of wellhead separators.

(B) Number of wells without wellhead separators.

(C) Total volume of oil production in barrels per year.

(D) Best estimate of fraction of production sent to tanks with assumed control measures: either vapor recovery system or flaring of tank vapors.

(E) Count of hydrocarbon tanks on well pads.

(F) Report CO_2 and CH_4 emissions collectively.

(iv) If wellhead separator dump valve is functioning improperly during the calendar year (refer to Equation W-16 of §98.233), report the following:

(A) Count of wellhead separators that dump valve factor is applied.

(9) For transmission tank emissions identified using optical gas imaging instrument per §98.234(a) (refer to §98.233(k)), or acoustic leak detection of scrubber dump valves report the following for each tank:

(i) Report emissions individually.

(ii) [Reserved]

(10) For well testing (refer to Equation W-17 of §98.233), report the following for each basin:

(i) Number of wells tested per basin in calendar year.

(ii) Average gas to oil ratio for each basin.

(iii) Average number of days the well is tested in a basin.

(iv) Report emissions of the venting gas collectively.

(11) For associated natural gas venting (refer to Equation W-18 of §98.233), report the following for each basin:

(i) Number of wells venting or flaring associated natural gas in a calendar year.

(ii) Average gas to oil ratio for each basin.

(iii) Report emissions of the flaring gas collectively.

(12) For flare stacks (refer to Equation W-19, W-20, and W-21 of §98.233), report the following for each flare:

(i) Whether flare has a continuous flow monitor.

(ii) Volume of gas sent to flare in cubic feet per year.

(iii) Percent of gas sent to un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

(iv) Whether flare has a continuous gas analyzer.

(v) Flare combustion efficiency.

(vi) Report uncombusted and combusted CO_2 and CH_4 emissions separately.

(13) For each centrifugal compressor:

(i) For compressors with wet seals in operational mode (refer to Equations W-22 through W-24 of §98.233), report the following for each degassing vent:

(A) Number of wet seals connected to the degassing vent.

(B) Fraction of vent gas recovered for fuel or sales or flared.

(C) Annual throughput in million scf, use an engineering calculation based on best available data.

(D) Type of meters used for making measurements.

(E) Reporter emission factor for wet seal oil degassing vents in cubic feet per hour (refer to Equation W-24 of §98.233).

(F) Total time the compressor is operating in hours.

(G) Report seal oil degassing vent emissions for compressors measured (refer to Equation W-22 of §98.233) and for compressors not measured (refer to Equation W-23 and Equation W-24 of §98.233).

(ii) For wet and dry seal centrifugal compressors in operating mode, (refer to Equations W-22 through W-24 of §98.233), report the following:

(A) Total time in hours the compressor is in operating mode.

(B) Reporter emission factor for blowdown vents in cubic feet per hour (refer to Equation W-24 of §98.233).

(C) Report blowdown vent emissions when in operating mode (refer to Equation W-23 and Equation W-24 of §98.233).

(iii) For wet and dry seal centrifugal compressors in not operating, depressurized mode (refer to Equations W-22 through W-24 of §98.233), report the following:

(A) Total time in hours the compressor is in shutdown, depressurized mode.

(B) Reporter emission factor for isolation valve emissions in shutdown, depressurized mode in cubic feet per hour (refer to Equation W-24 of §98.233).

(C) Report the isolation valve leakage emissions in not operating, depressurized mode in cubic feet per hour (refer to Equation W-23 and Equation W-24 of §98.233).

(iv) Report total annual compressor emissions from all modes of operation (refer to Equation W-24 of §98.233).

(v) For centrifugal compressors in onshore petroleum and natural gas production (refer to Equation W-25 of §98.233), report the following:

(A) Count of compressors.

(B) Report emissions (refer to Equation W-25 of §98.233) collectively.

(14) For reciprocating compressors:

(i) For reciprocating compressors rod packing emissions with or without a vent in operating mode, report the following:

(A) Annual throughput in million scf, use an engineering calculation based on best available data.

(B) Total time in hours the reciprocating compressor is in operating mode.

(C) Report rod packing emissions for compressors measured (refer to Equation W-26 of §98.233) and for compressors not measured (refer to Equation W-27 and Equation W-28 of §98.233).

(ii) For reciprocating compressors blowdown vents not manifold to rod packing vents, in operating and standby pressurized mode (refer to Equations W-26 through W-28 of §98.233), report the following:

(A) Total time in hours the compressor is in standby, pressurized mode.

(B) Reporter emission factor for blowdown vents in cubic feet per hour (refer to §98.233, Equation W-28).

(C) Report blowdown vent emissions when in operating and standby pressurized modes (refer to Equation W-27 and Equation W-28 of §98.233).

(iii) For reciprocating compressors in not operating, depressurized mode (refer to Equations W-26 through W-28 of §98.233), report the following:

(A) Total time the compressor is in not operating, depressurized mode.

(B) Reporter emission factor for isolation valve emissions in not operating, depressurized mode in cubic feet per hour (refer to Equation W-28 of §98.233).

(C) Report the isolation valve leakage emissions in not operating, depressurized mode.

(iv) Report total annual compressor emissions from all modes of operation (refer to Equation W-27 and Equation W-28 of §98.233).

(v) For reciprocating compressors in onshore petroleum and natural gas production (refer to Equation W-29 of §98.233), report the following:

(A) Count of compressors.

(B) Report emissions collectively.

(15) For each equipment leak sources that uses emission factors for estimating emissions (refer to §98.233(q) and (r).

(i) For equipment leaks found in each leak survey (refer to §98.233(q)), report the following:

(A) Total count of leaks found in each complete survey listed by date of survey and each type of leak source for which there is a leaker emission factor in Tables W-2, W-3, W-4, W-5, W-6, and W-7 of this subpart.

(B) Concentration of CH_4 and CO_2 as described in Equation W-30 of §98.233.

(C) Report CH_4 and CO_2 emissions (refer to Equation W-30 of §98.233) collectively by equipment type.

(ii) For equipment leaks calculated using population counts and factors (refer to §98.233(r)), report the following:

(A) For source categories §98.230(a)(3), (a)(4), (a)(5), (a)(6), and (a)(7), total count for each type of leak source in Tables W-2, W-3, W-4, W-5, and W-6 of this subpart for which there is a population emission factor, listed by major heading and component type.

(B) For onshore production (refer to §98.230 paragraph (a)(2)), total count for each type of major equipment in Table W-1B and Table W-1C of this subpart, by field.

(C) Report CH_4 and CO_2 emissions (refer to Equation W-31 of §98.233) collectively by equipment type.

(16) For local distribution companies, report the following:

(i) Number of custody transfer gate stations.

(ii) Number of non-custody transfer gate stations.

(iii) Custody transfer gate station meter run leak factor (refer to Equation W-32 of §98.233).

(iv) Number of below grade M&R stations with inlet pressure greater than 300 psig.

(v) Number of below grade M&R stations with inlet pressure between 100 and 300 psig.

(vi) Number of below grate M&R stations with inlet pressure less than 100 psig.

(vii) Number of miles of unprotected steel distribution mains.

(viii) Number of miles of protected steel distribution mains.

(ix) Number of miles of plastic distribution mains.

(x) Number of miles of cast iron distribution mains.

(xi) Number of unprotected steel distribution services.

(xii) Number of protected steel distribution services.

(xiii) Number of plastic distribution services.

(xiv) Number of copper distribution services.

(xv) Total emissions from each natural gas distribution facility.

(17) For each EOR injection pump blowdown (refer to Equation W-37 of §98.233), report the following:

(i) Pump capacity, in barrels per day.

(ii) Volume of critical phase gas between isolation valves.

(iii) Number of blowdowns per year.

(iv) Critical phase EOR injection gas density.

(v) Report emissions collectively.

(18) For EOR hydrocarbon liquids dissolved CO_2 for each field (refer to Equation W-38 of §98.233), report the following:

(i) Volume of crude oil produced in barrels per year.

(ii) Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

(iii) Report emissions individually.

(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:

(i) Cumulative number of external fuel combustion units with a rated heat capacity equal to or less than 5 mmBtu/hr, by type of unit.

(ii) Cumulative number of external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by type of unit.

(iii) Cumulative emissions from external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by type of unit.

(iv) Cumulative volume of fuel combusted in external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by fuel type.

(v) Cumulative number of all internal combustion units, by type of unit.

(vi) Cumulative emissions from internal combustion units, by type of unit.

(vii) Cumulative volume of fuel combusted in internal combustion units, by fuel type.

(d) Report annual throughput as determined by engineering estimate based on best available data for each industry segment listed in paragraphs (a)(1) through (a)(8) of this section.

§98.237 Records that must be retained.

Monitoring Plans, as described in §98.3(g)(5), must be completed by April 1, 2011. In addition to the information required by §98.3(g), you must retain the following records:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

§98.238 Definitions.

Except as provided in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Acid gas means hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent emissions mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Basin means geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see §98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see §98.7).

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

Condensate means hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.

Engineering estimation, for purposes of subpart W, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Equipment leak means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Facility with respect to natural gas distribution for purposes of this subpart and for subpart A means the collection of all distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to onshore petroleum and natural gas production for purposes of this subpart and for subpart A means all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in §98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Farm Taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. The gas may or may not be metered, but always does not pass through a city gate station. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

Field means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08) (incorporated by reference, see §98.7).

Flare stack emissions means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares.

Flare combustion efficiency means the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip.

Gas well means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

LNG boil-off gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

Oil well means a well completed for the production of crude oil from at least one oil zone or reservoir.

Onshore petroleum and natural gas production owner or operator means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued**,** which operates an onshore petroleum and/or natural gas production facility (as described in §98.230(a)(2). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue Gas and Residue Gas Compression mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Transmission pipeline means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Vented emissions means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

TABLE W-1A OF SUBPART W–DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION

Onshore petroleum and natural gas production	Emission Factor (scf/hour/component)
Eastern U.S.	
Population Emission Factors - All Components, Gas Service[1]	
Valve	0.027
Connector	0.004
Open-ended Line	0.062
Pressure Relief Valve	0.041
Low Continuous Bleed Pneumatic Device Vents[2]	1.80
High Continuous Bleed Pneumatic Device Vents[2]	48.1
Intermittent Bleed Pneumatic Device Vents[2]	17.4
Pneumatic Pumps[3]	13.3
Population Emission Factors - All Components, Light Crude Service[4]	
Valve	0.04
Flange	0.002
Connector	0.005
Open-ended Line	0.04
Pump	0.01
Other[5]	0.23
Population Emission Factors - All Components, Heavy Crude Service[6]	
Valve	0.0004
Flange	0.0007
Connector (other)	0.0002
Open-ended Line	0.004

TABLE W-1A OF SUBPART W–DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION

Onshore petroleum and natural gas production	Emission Factor (scf/hour/component)
Other[5]	0.002
Western U.S.	
Population Emission Factors - All Components, Gas Service[1]	
Valve	0.123
Connector	0.017
Open-ended Line	0.032
Pressure Relief Valve	0.196
Low Continuous Bleed Pneumatic Device Vents[2]	1.80
High Continuous Bleed Pneumatic Device Vents[2]	48.1
Intermittent Bleed Pneumatic Device Vents[2]	17.4
Pneumatic Pumps[3]	13.3
Population Emission Factors - All Components, Light Crude Service[4]	
Valve	0.04
Flange	0.002
Connector (other)	0.005
Open-ended Line	0.04
Pump	0.01
Other[5]	0.23
Population Emission Factors - All Components, Heavy Crude Service[6]	
Valve	0.0004
Flange	0.0007
Connector (other)	0.0002
Open-ended Line	0.004
Other[5]	0.002

[1] For multi-phase flow that includes gas, use the gas service emissions factors

[2] Emission Factor is in units of "scf/hour/device"

[3] Emission Factor is in units of "scf/hour/pump"

[4] Hydrocarbon liquids greater than or equal to 20˚API are considered "light crude"
[5] ”Others” category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

[6] Hydrocarbon liquids less than 20˚API are considered "heavy crude"

TABLE W-1B OF SUBPART W–DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR ONSHORE NATURAL GAS PRODUCTION EQUIPMENT

Major Equipment	Valves	Connectors	Open-ended Lines	Pressure relief valves
Eastern U.S.				
Wellheads	8	38	0.5	0
Separators	1	6	0	0
meters/piping	12	45	0	0
Compressors	12	57	0	0
In-line heaters	14	65	2	1

TABLE W-1B OF SUBPART W–DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR ONSHORE NATURAL GAS PRODUCTION EQUIPMENT

Major Equipment	Valves	Connectors	Open-ended Lines	Pressure relief valves
Dehydrators	24	90	2	2
Western U.S.				
Wellheads	11	36	1	0
Separators	34	106	6	2
meters/piping	14	51	1	1
Compressors	73	179	3	4
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2

TABLE W-1C OF SUBPART W OF PART 98–DEFAULT AVERGE COMPONENT COUNTS FOR MAJOR CRUDE OIL PRODUCTION EQUIPMENT

Major Equipment	Valves	Flanges	Connectors	Open-ended Lines	Other Components
Eastern U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0
Western U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0

Table W-1D OF SUBPART W OF PART 98–DESIGNATION OF EASTERN AND WESTERN U.S.

Eastern U.S.	Western U.S.
Connecticut	Alabama
Delaware	Alaska
Florida	Arizona
Georgia	Arkansas
Illinois	California
Indiana	Colorado
Kentucky	Hawaii
Maine	Idaho
Maryland	Iowa
Massachusetts	Kansas
Michigan	Louisiana
New Hampshire	Minnesota
New Jersey	Mississippi
New York	Missouri
North Carolina	Montana
Ohio	Nebraska
Pennsylvania	Nevada
Rhode Island	New Mexico

Table W-1D OF SUBPART W OF PART 98–DESIGNATION OF EASTERN AND WESTERN U.S.

Eastern U.S.	Western U.S.
South Carolina	North Dakota
Tennessee	Oklahoma
Vermont	Oregon
Virginia	South Dakota
West Virginia	Texas
Wisconsin	Utah
	Washington
	Wyoming

TABLE W-2 OF SUBPART W–DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING

Onshore natural gas processing	Emission Factor (scf/hour/component)
Leaker Emission Factors - Compressor Components, Gas Service	
Valve[1]	15.07
Connector	5.68
Open-Ended Line	17.54
Pressure Relief Valve	40.27
Meter	19.63
Leaker Emission Factors – Non-Compressor Components, Gas Service	
Valve	6.52
Connector	5.80
Open-Ended Line	11.44
Pressure Relief Valve	2.04
Meter	2.98

[1] Valves include control valves, block valves and regulator valves.

TABLE W-3 OF SUBPART W–DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Onshore natural gas transmission compression	Emission Factor (scf/hour/component)
Leaker Emission Factors - Compressor Components, Gas Service	
Valve[1]	15.07
Connector	5.68
Open-Ended Line	17.54
Pressure Relief Valve	40.27
Meter	19.63
Leaker Emission Factors – Non-Compressor Components, Gas Service	
Valve[1]	6.52
Connector	5.80
Open-Ended Line	11.44
Pressure Relief Valve	2.04
Meter	2.98
Population Emission Factors – Gas Service	

TABLE W-3 OF SUBPART W–DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Onshore natural gas transmission compression	Emission Factor (scf/hour/component)
Low Continuous Bleed Pneumatic Device Vents[2]	1.41
High Continuous Bleed Pneumatic Device Vents[2]	18.8
Intermittent Bleed Pneumatic Device Vents[2]	18.8

[1] Valves include control valves, block valves and regulator valves.

[2] Emission Factor is in units of "scf/hour/device"

TABLE W-4 OF SUBPART W–DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission Factor (scf/hour/component)
Leaker Emission Factors - Storage Station, Gas Service	
Valve[1]	15.07
Connector	5.68
Open-Ended Line	17.54
Pressure Relief Valve	40.27
Meter	19.63
Population Emission Factors - Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.10
Pressure Relief Valve	0.17
Open-ended Line	0.03
Population Emission Factors - Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents[2]	1.41
High Continuous Bleed Pneumatic Device Vents[2]	18.8
Intermittent Bleed Pneumatic Device Vents[2]	18.8

[1] Valves include control valves, block valves and regulator valves.

[2] Emission Factor is in units of "scf/hour/device"

TABLE W-5 OF SUBPART W–DEFAULT METHANE EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE

LNG Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors - LNG Storage Components, LNG Service	
Valve	1.21
Pump Seal	4.06
Connector	0.35
Other[1]	1.80
Population Emission Factors - LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor[2]	4.23

1 "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.

2 Emission Factor is in units of "scf/hour/compressor"

TABLE W-6 OF SUBPART W–DEFAULT METHANE EMISSION FACTORS FOR LNG IMPORT AND EXPORT EQUIPMENT

LNG import and export equipment	Emission Factor (scf/hour/component)
Leaker Emission Factors - LNG Terminals Components, LNG Service	
Valve	1.21
Pump Seal	4.06
Connector	0.35
Other1	1.80
Population Emission Factors - LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor2	4.23

1 "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
2 Emission Factor is in units of "scf/hour/compressor"

TABLE W-7 OF SUBPART W–DEFAULT METHANE EMISSION FACTORS FOR NATURAL GAS DISTRIBUTION

Natural gas distribution	Emission Factor (scf/hour/component)
Leaker Emission Factors - Above Grade M&R at City Gate Stations[1] Components, Gas Service	
Connector	1.72
Block Valve	0.566
Control Valve	9.48
Pressure Relief Valve	0.274
Orifice Meter	0.215
Regulator	0.784
Open-ended Line	26.533
Population Emission Factors - Below Grade M&R[2] Components, Gas Service[3]	
Below Grade M&R Station, Inlet Pressure > 300 psig	1.32
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure < 100 psig	0.10
Population Emission Factors - Distribution Mains, Gas Service[4]	
Unprotected Steel	12.77
Protected Steel	0.36
Plastic	1.15
Cast Iron	27.67
Population Emission Factors - Distribution Services, Gas Service[5]	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1] City gate stations at custody transfer and excluding customer meters
[2] Excluding customer meters
[3] Emission Factor is in units of "scf/hour/station"
[4] Emission Factor is in units of "scf/hour/mile"
[5] Emission Factor is in units of “scf/hour/number of services”